Final
Determination of Compliance

Metcalf Energy Center

Bay Area Air Quality Management District
Application 27215

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I Background

This is the Final Determination of Compliance (FDOC) for the Metcalf Energy Center (MEC), a 600-MW, natural-gas fired, combined cycle merchant power plant proposed by Calpine Corporation and Bechtel Enterprises, Inc. The power plant will be located at the southern edge of the city of San Jose in Santa Clara County and will be composed of two nominal 200-MW "F-class" combustion gas turbines, two heat recovery steam generators equipped with 200 MM BTU/hr duct burners and one 235-MW steam turbine generator. The facility will also include an exempt 300-hp fire pump diesel engine and an exempt natural gas fired 6.44 MM BTU/hr emergency generator.

Pursuant to BAAQMD Regulation 2, Rule 3, Section 405, this document serves as the Final Determination of Compliance (FDOC) document for the Metcalf Energy Center. It will also serve as the evaluation report for the BAAQMD Authority to Construct application #27215 and the final Prevention of Significant Deterioration (PSD) permit. Because the US EPA is currently involved in a consultation with the U.S. Fish and Wildlife Service pursuant to Section 7 of the Federal Endangered Species Act, the PSD permit conditions contained in this document may be revised to reflect the outcome of the consultation.

The FDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

In accordance with BAAQMD Regulation 2, Rule 3, Section 404, this FDOC has fulfilled the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407.

II Project Description

1. Process Equipment

The applicant is proposing a combined-cycle combustion turbine power generation facility with a maximum electrical output of 600 MW. The Metcalf Energy Center will consist of the following permitted equipment:

S-1 Combustion Gas Turbine #1, Westinghouse 501FD2; 1,990.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-1 Selective Catalytic Reduction System

S-2 Heat Recovery Steam Generator #1, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-1 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #2, Westinghouse 501FD2; 1,990.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-2 Selective Catalytic Reduction System

S-4 Heat Recovery Steam Generator #2, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-2 Selective Catalytic Reduction System

As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 200 MW and the steam produced by both heat recovery steam generators (HRSGs) will feed to a single steam turbine generator with a nominal electrical output of 235 MW.

The Metcalf Energy Center will also include the following pieces of equipment that are exempt from District permit requirements:

- Fire Pump Diesel Engine, Cummins Model 6CTA8.3-F3; 300 hp

  (exempt from District permit requirements pursuant to Regulation 2-1-114.2.3.1, since it will be operated for no more than 200 hours per calendar year, plus an additional 100 hours per calendar year for the purposes of maintenance and testing)

- Emergency Generator, Caterpillar Model G3612-TA, Natural Gas Fired, 6.44 MM BTU/hr

  (exempt from District permit requirements pursuant to Regulation 2-1-114.2.3.1, since it will be operated for no more than 200 hours per calendar year, plus an additional 100 hours per calendar year for the purposes of maintenance and testing)

As proposed, the Metcalf Energy Center will also include a 10-Cell Wet Cooling Tower that was exempt from District permit requirements pursuant to Regulation 2-1-128.4 when this application was originally submitted to the District. However, District Regulation 2-1-319.1, which was adopted on May 17, 2000, requires a permit to operate for any source that emits greater than 5 tons per year of any regulated air pollutant. With estimated annual PM_{10} emissions of approximately 8 tons per year, the cooling tower will therefore require a permit to operate under this regulation. Because this application was deemed complete prior to May 17, 2000, the authority to construct review for the cooling tower will not be included in this FDOC. Rather, the applicant must submit a separate application for an authority to construct and permit to operate the cooling tower. Under that application, the cooling tower will be subject to a BACT review under the District new source review regulation.

2. Equipment Operating Scenarios

Turbines and Heat Recovery Steam Generators

As a merchant power plant, market circumstances and demand will dictate the exact operation of the new gas turbine/HRSG power trains. However, the following general operating modes are projected to occur:

Base Load: Maximum continuous output with duct firing and power augmentation steam injection during high ambient temperature conditions

Load Following: Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario

Partial Shutdown: Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during period of low overall demand such as late evening and early morning hours

Full Shutdown: May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation

HRSG Duct Burner Firing with Steam Injection Power Augmentation:

Under peak demand situations and high ambient temperatures, steam may be injected downstream of gas turbine combustors to lower the temperature of the combustion products and allow an increased fuel use rate, which results in increased mass flow through the gas turbine thereby increasing maximum electrical output.

The following projected operating scenario was utilized to estimate maximum annual air pollutant emissions from the new gas turbines and HRSGs.

- 6,844 hours of baseload (100% load) operation per year for each gas turbine @ 30^{o}F
- 1,500 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 260 one-hour hot start-ups per gas turbine per year
- 52 three-hour cold start-ups per gas turbine per year

3. Air Pollution Control Strategies and Equipment

The proposed Metcalf Energy Center includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (NO_x), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide (SO_2), and particulate matter of less than 10 microns in diameter (PM_{10}).

a. Selective Catalytic Reduction with Ammonia Injection for the Control of NO_x

The gas turbines and HRSG duct burners each trigger BACT for NO_x emissions. The gas turbines will be equipped with dry low-NO_x (DLN) combustors, which minimize NO_x emissions by lowering peak flame temperature by premixing combustion air with a lean fuel mixture. The HRSGs will be equipped with low-NO_x duct burners, which are designed to minimize NO_x emissions. In addition, the combined NO_x emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection.

b. Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to Minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-NO_x combustors, which operate on a lean fuel mixture that minimizes CO emissions. The HRSGs will be equipped with low-NO_x duct burners, which are also designed to minimize CO emissions. Furthermore, the HRSGs and will be designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations. The gas turbine and HRSG duct burner combined exhaust will achieve a CO emission limit of 6 ppmvd @ 15% O_2, which exceeds the current District BACT Guideline of 10 ppmvd @ 15% O_2.

c. Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to Minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-NO_x combustors which are designed to minimize incomplete combustion and therefore minimize POC emissions. The HRSGs will be equipped with low-NO_x duct burners, which are also designed to minimize incomplete combustion and therefore minimize POC emissions. The gas turbine and HRSG duct burner combined exhaust will achieve a POC emission limit of 1 ppmvd @ 15% O_2

d. Exclusive Use of Clean-burning Natural gas to Minimize SO_2 and PM_{10} Emissions

The gas turbines and HRSG duct burners will utilize exclusively natural gas as a fuel to minimize SO_2 and PM_{10} emissions. Because the emission rate of SO_2 depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of natural gas will result in the lowest possible emission of SO_2. PM_{10} emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

III Facility Emissions

The facility regulated air pollutant emissions and toxic air contaminant emissions are presented in the following tables. Detailed emission calculations, including the derivations of emission factors are presented in the appendices.

Table 1 is a summary of the daily maximum regulated air pollutant emissions for the gas turbines and heat recovery steam generators (HRSGs). These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of the District New Source Review Regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that will result in POC, NPOC, NO_x, SO_2, PM_{10}, or CO emissions in excess of 10 pounds per highest day per pollutant are subject to the BACT requirement for that pollutant.

Table 1 Maximum Daily Regulated Air Pollutant Emissions for Proposed Sources[a] (lb/day)

Pollutant	Source	
	S-1 CTG & S-2 HRSG	S-3 CTG & S-4 HRSG
Nitrogen Oxides (as NO_2)	699.2	699.2
Carbon Monoxide	3,970.3	3,970.3
Precursor Organic Compounds	117.2	117.2
Particulate Matter (PM_{10})	216	216
Sulfur Dioxide	30.1	30.1

[a] Based upon one 3-hour cold start-up, one 1-hour hot startup, 16 hours of CTG/HRSG baseload operation at maximum combined firing rate of 2,124 MM BTU/hr with steam injection power augmentation at the gas turbine combustors and four hours of 100% load CTG operation at 1,990.5 MM BTU/hr in one day

Table 2 is a summary of the maximum facility toxic air contaminant (TAC) emissions from new sources. These emissions are used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 5 ppmvd @ 15% O_2 due to ammonia slip from the A-1 and A-2 SCR Systems.

Table 2 Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb/yr-source)
Each Gas Turbine and HRSG (S-1 & S-2, S-3 & S-4)		
Acetaldehyde[b]	1,183	72
Acrolein	111	3.9
Ammonia[c]	118,168	19,300
Benzene[b]	2,346	6.7
1,3-Butadiene[b]	2.2	1.1
Ethylbenzene	3,087	193,000
Formaldehyde[b]	1,897	33
Hexane	4,467	83,000
Naphthalene	28.6	270
PAHs[b]	40	0.043
Propylene	13,282	none specified
Propylene Oxide[b]	825	52
Toluene	1,225	38,600
Xylenes	450	57,900
Cooling Tower		
Aluminum	16	none specified
Arsenic[b]	0.0204	0.024
Cadmium[b]	0.015	0.046
Trivalent chromium[b]	0.009	0.0014
Copper	0.06	463
Lead[b]	0.16	29
Mercury	0.0013	57.9
Nickel	0.11	96.5
Silver	0.015	none specified
Zinc	0.72	6,760
Fire Pump Diesel Engine		
Diesel Exhaust Particulate	17	0.64
Benzene	0.2	6.7
Toluene	0.09	38,600
Xylenes	0.06	57,900
Propylene	0.54	none specified
1,3-Butadiene	0.008	1.1
Formaldehyde	0.25	33
Acetaldehyde	0.2	72

Acrolein	0.02	3.9
Total PAHs	0.035	0.043

[a]pursuant to BAAQMD Toxic Risk Management Policy

[b]carcinogenic compound

[c]based upon the worst-case ammonia slip of 5 ppmvd NH_3 @ 15% O_2 from the A-1 and A-2 SCR systems with ammonia injection

Table 3 is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of the trigger levels shown must perform modeling to assess the net air quality impact of that pollutant.

Table 3
Maximum Annual Facility Regulated Air Pollutant Emissions

Pollutant	Permitted Source Emissions[a,b] (tons/year)	PSD Trigger[c] (tons/year)	Total Facility Emissions[d] (tons/year)
Nitrogen Oxides (as NO_2)	123.43[e]	100	124
Carbon Monoxide	588	100	588.5
Precursor Organic Compounds	28	N/A[f]	28.2
Particulate Matter (PM_{10})	83.34	100	91.29
Sulfur Dioxide	10.58	100	10.58

[a]emission increases from proposed gas turbines and heat recovery steam generators only; does not include emissions from cooling tower or standby engines

[b]Includes start-up emissions for gas turbines (52 total cold start-ups and 260 total hot start-ups per year per turbine)

[c]for a new major facility

[d]includes emissions from exempt cooling tower and standby engines

[e]reduced annual limit proposed by applicant based upon average NOx emission rate of 2.0 ppmv and average number of turbine start-ups per year; annual limit for any consecutive twelve month period that includes any portion of the commissioning period will remain at 185.24 tons per year

[f]there is no PSD requirement for POC since the BAAQMD is designated as nonattainment for the federal 1-hour ambient air quality standard for ozone

IV Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed Metcalf Energy Center will comply with those requirements.

A. Regulation 2, Rule 2; New Source Review

The primary requirements of New Source Review that apply to the proposed MEC facility are Section 2-2-301; "Best Available Control Technology Requirement", Section 2-2-302; "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR", and Section 2-2-404, "PSD Air Quality Analysis".

1. Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source: or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO, or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and it must be commercially available, demonstrated to be effective and reliable on a full-scale unit, and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The following section includes BACT determinations by pollutant for the permitted sources of the proposed Metcalf Energy Center. Because each Gas Turbine and its associated HRSG will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/HRSG power train as a combined unit.

Nitrogen Oxides (NO_x)

- Combustion Gas Turbines

  District BACT Guideline 89.2.1 specifies BACT 2 (achieved in practice) for NO_x for a gas turbine with a rated heat input $\geq$ 23 MM BTU per hour as NO_x emissions < 5 ppmvd @ 15% O_2, typically achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with combustion modifications. The SCAQMD BACT Guideline for gas turbines $\geq$ 3 MW specifies BACT 1 for NO_x as 2.5 ppmvd, @ 15% O_2 with an efficiency correction factor and an assumed averaging period of one hour. This BACT determination was based upon the demonstration of a SCONOX system on a 32 MW combined cycle, baseload turbine currently in operation in Vernon, California. The EPA has accepted this BACT determination as Federal LAER and further established a NO_x concentration of 2.0 ppmvd @ 15% O_2 averaged over three hours as equivalent to 2.5 ppmvd, @ 15% O_2, averaged over one hour.

  In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.5 ppmvd NO_x @ 15% O_2, averaged over one hour at, during all operating modes except gas turbine start-ups and shutdowns. This exceeds the current District BACT determination and meets the EPA and ARB BACT determination for NO_x. Compliance with this emission limitation will be achieved through the use of a selective catalytic reduction (SCR) system with ammonia injection and will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

- Heat Recovery Steam Generators (HRSGs)

  Supplemental heat will be supplied to the HRSGs with dry low-NO_x duct burners, which are designed to minimize NO_x emissions. The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve NO_x emission concentrations of 2.5 ppmvd @ 15% O_2, averaged over one hour.

Top-Down BACT Analysis

In response to comments from EPA Region 9 and various intervenors, the following “top-down” BACT analysis for NO_x has been prepared in accordance with EPA’s 1990 Draft New Source Review Workshop Manual. A “top-down” BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring.

Available Control Options and Technical Feasibility

In a March 24, 2000 letter sent to local air pollution control districts, EPA Region 9 stated that the $SCONO_x$ Catalytic Adsorption System should be included in any BACT/LAER analysis for combined cycle gas turbine power plant projects since it can achieve the BACT/LAER emission specification for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour or 2.0 ppmvd @ 15% O_2, averaged over three hours. In this letter, EPA stated that ABB Alstom Power, the exclusive licensee for $SCONO_x$ applications, has conducted "full-scale damper testing" that demonstrates that $SCONO_x$ is technically feasible for gas turbines of the size proposed for the Metcalf Energy Center. Stone & Webster Management Consultants, Inc. of Denver Colorado was subsequently hired by ABB to conduct an independent technical review of the $SCONO_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve unacceptable reliability and leakage problems. However, no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because the feasibility of the "scale-up" of the $SCONO_x$ system for large turbines has not been demonstrated, we do not consider $SCONO_x$ to be a viable control alternative for NO_x.

Although we do not consider SCONOx to be a technically feasible control alternative for this project, we have analyzed the collateral impacts of both SCR and $SCONO_x$. We are providing the following analysis for informational purposes only. The analysis shown in Table 4 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a NO_x emission rate of 25 ppmvd @ 15% O_2.

Table 4 Top-Down BACT Analysis Summary for NO_x

Control Alternative	Emissions[a] (ton/yr)	Emission Reduction[b] (ton/yr)	Total Annualized Cost[c] ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)	Toxic Impacts	Adverse Environmental Impacts	Incremental Energy Impact (MM BTU/yr)
$SCONO_x$	788	709	4,122,889	5,815	N/A[d]	No	No	122,000[e]
SCR	788	709	1,557,125	2,196	-	Yes	No	67,900[e]

[a]based upon NO_x emission rate of 25 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[b]based upon NO_x emission rate after abatement of 2.5 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[c]"Cost Analysis for NO_x Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999

[d]does not apply since there is no difference in emission reduction quantity between alternatives

[e]"Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

Energy Impacts

As shown in Table 4, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of $SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

Economic Impacts

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in Table 4, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of NO_x abated. However, the average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by ONSITE SYCOM Energy Corporation. Although SCONOx will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendix F for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour and therefore achieve the same NO_x emission reduction in tons per year.

Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15 % O_2. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.018 and a chronic hazard index of 0.0131 resulting from the ammonia slip emissions. In accordance with the District Toxic Risk Management Policy and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The MEC will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed MEC facility and found that the impact would not be significant. Therefore, the potential enivronmental impact due to aqueous ammonia storage at the MEC does not justify the elimination of SCR as a control alternative.

The use of SCONOx will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

Conclusion

Because both SCR and $SCONO_x$ can achieve the current accepted BACT/LAER specification for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour or 2.0 ppmvd @ 15% O_2, averaged over three hours and neither will cause significant energy, economic, or environmental impacts, neither can be eliminated as viable control alternatives. Therefore, the applicant's proposed use of SCR to meet the NO_x BACT/LAER specification is deemed acceptable.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of three distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing. The third mode includes gas turbine firing at maximum load with HRSG duct burner firing and steam injection power augmentation at the gas turbine combustors. Steam injection power augmentation lowers the combustor flame temperature (allowing an increased fuel use rate) and increases mass flow through the turbine blades, which in turn increases gas turbine peak generating capacity during periods of high ambient temperature.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

District BACT Guideline 89.2.1 specifies BACT 2 (achieved in practice) for CO for gas turbines with a rated heat input $\geq$ 23 MM BTU per hour as a CO emission concentration of 10 ppmvd @ 15% O_2. BACT 1 (technologically feasible/cost-effective) is specified as a CO emission concentration of < 6 ppmvd @ 15% O_2. Both BACT specifications do not specify gas turbine/HRSG operating mode. It should be noted that BACT Guideline 89.2.1 is currently being revised to reflect recently permitted gas turbine facilities.

When the Crockett Cogeneration facility was originally permitted in 1993 at a CO emission concentration limit of 5.9 ppmvd @ 15% O_2 (through the use of an oxidation catalyst), it established the technologically feasible/cost-effective BACT emission limitation cited above. However, subsequent operation of the facility has shown that they cannot achieve this emission concentration under all operating modes and ambient conditions. Specifically, CO emissions exceed 5.9 ppmvd during minimum load operation under ambient conditions of low temperature and high relative humidity and during peak load operation under ambient conditions of high temperature and moderate to high relative humidity. However, Crockett Cogeneration expects that the gas turbine will comply with a CO emission concentration limit of 10 ppmvd @ 15% O_2 under all loads and ambient conditions with and without duct burner firing. Crockett has not employed steam injection power augmentation during peak load/high ambient temperature situations since the resulting CO emission concentration would exceed the current emission limit of 5.9 ppmvd CO. Based upon their operating experience, they do not expect to consistently meet 10 ppmvd CO when operating in steam injection power augmentation mode. Therefore, the achieved-in-practice BACT for CO does not apply to the steam injection power augmentation mode.

The Los Medanos Energy Center (formerly Pittsburg District Energy Facility) was permitted at a CO emission concentration limit of 6 ppmvd @ 15% O_2 during all operating modes except for gas turbine start-up and shutdown. This limit applies to the combined exhaust from the gas turbine and HRSG and is predicated upon the use of an oxidation catalyst. Because the PDEF proposed this limit, it was accepted as meeting BACT for CO. However, it is not considered achieved-in-practice BACT since it has not yet been demonstrated consistently under actual operating conditions.

With the agreement of the ARB and EPA Region 9, the Delta Energy Center (DEC) was recently permitted at a CO emission concentration limit of 10 ppmvd @ 15% O_2, averaged over any consecutive three hour period, that will apply to all operating modes except turbine start-up and shutdown. The DEC will comply with this BACT specification through the use of dry low-NO_x duct burners which minimize incomplete combustion and without the use of an oxidation catalyst.

Top-Down BACT Analysis

In response to comments from EPA Region 9, the following "top-down" BACT analysis for CO has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual.

Available Control Options and Technical Feasibility

The CO control options that have been cited for the proposed combined-cycle gas turbines at MEC include $SCONO_x$, catalytic oxidation, and combustion control (DLN Combustors). Representatives of $SCONO_x$ provide performance guarantees of 90% by weight for CO for gas turbines equipped with conventional combustors. They have not extended the guarantee to gas turbines equipped with DLN combustors which produce extremely low CO emissions of < 10 ppmvd @ 15% O_2. Because the ability of $SCONO_x$ to control CO has not been demonstrated on a gas turbine comparable to those proposed for the Metcalf Energy Center and because EPA has not identified SCONOx as BACT for CO, $SCONO_x$ is deemed to be a technically infeasible control alternative for CO.

As discussed above, we are not aware of any operating gas turbine comparable to those proposed for the Metcalf Energy Center (with or without an oxidation catalyst) that has achieved CO emission concentrations of 6 ppmvd or less over all operating modes and ambient conditions except start-up and shutdown. Therefore, BACT for CO is deemed to be an emission limitation of 10 ppmvd @ 15% O_2, averaged over three hours.

The MEC has agreed to a CO emission limit of 6 ppmvd @ 15% O_2, averaged over 3 hours, that will apply when the heat input to the gas turbine exceeds 1700 MM BTU/hr (HHV) which corresponds to 85% load. In addition, the CO mass emission rate cannot exceed the full load rate of 28.07 pounds per hour under any turbine/HRSG operating modes, except start-up and shutdown. This hybrid limit will allow for CO emission concentrations to exceed 6 ppmvd under low load conditions, when the gas turbine combustors are not operating in their optimal range, while insuring that mass CO emissions never exceed full load emission rates. Furthermore, permit condition 20(d) contains a provision requiring the reduction of the CO limit to a level not less than 4 ppmvd, based upon future source test results and CEM data from the actual operation of the MEC. EPA Region IX, ARB, and the CEC have agreed to this condition format as BACT for CO. This emission limit is more stringent than the current District BACT 2 specification of 10 ppmvd @ 15% O_2, averaged over three hours and equivalent to the District BACT 1 and ARB BACT specification of 6 ppmvd @ 15% O_2, averaged over three hours.

The MEC will comply with this BACT specification through the use of dry low-NO_x duct burners that minimize incomplete combustion and without the use of an oxidation catalyst. Permit condition 23 requires that the HRSG be designed and constructed so that it can readily accept an oxidation catalyst. If the MEC cannot consistently meet these emission limitations, the Air Pollution Control Officer (APCO) may require the installation of an oxidation catalyst.

Precursor Organic Compounds (POCs)

- Combustion Gas Turbines

  Currently, District BACT Guideline 89.2.1 specifies BACT 2 (achieved in practice) for POC for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as 50% reduction by weight which is typically achieved through the use of an oxidation catalyst. BACT 1 (technologically feasible/cost-effective) is listed as > 50% reduction by weight, typically achieved through the use of an oxidation catalyst. These determinations were based upon District application #8658 for the Crockett Cogeneration Facility (170 MW GE 7FA) and application 10962 for UCSF Central Utilities Plant (5 MW Solar Centaur Taurus). However, a BACT determination based solely upon a weight percent reduction is not effective since the resulting emission rate at the stack is dependent upon the inlet concentration which is not limited. Therefore, these BACT determinations are undergoing revisions and will be expressed as an emission concentration (or equivalent emission factor) at the stack. Crockett Cogeneration is permitted at a POC emission concentration of 6.5 ppmvd @ 15% O_2 or 0.0061 lb/MM BTU. The UCSF Central Utilities Plant is permitted at a POC emission limit of 0.01 lb/MM BTU. The results of 4 annual source tests of the gas turbine and HRSG duct burners at the Crockett Cogeneration Facility have not exceeded 1 ppmvd POC @ 15% O_2. Because the source tests provide only a "snapshot" of the operation of the turbine, they do not substantiate an BACT 2 (achived in practice) determination since the testing does not capture the entire operating range of the turbine. The Delta Energy Center established a BACT 1 (technologically feasible/cost-effective) determination for POC when it was recently permitted at a POC emission limit of 2 ppmvd @ 15% O_2.

  The applicant has agreed to a POC emission limitations of 2.7 pounds per hour and 0.00126 lb/MM BTU that are equivalent to an emission concentration of 1 ppmvd @ 15% O_2. Because this emission limitation is more stringent than the current BAAQMD BACT 1 determination and the current ARB BACT determination for POC of 2 ppmvd @ 15% $O_{2,}$, averaged over 1 hour, as promulgated in their July 22, 1999 power plant siting guidance document, MEC satisfies BACT for POC.

- Heat Recovery Steam Generators (HRSGs)

  The HRSG duct burners will be of dry, low-NO_x design, which minimizes incomplete combustion and the POC emission rate. The applicant has agreed to a combined POC emission concentration limit of 1.0 ppmvd @ 15% O_2 for simultaneous firing of the turbine and HRSG duct burners, without the use of an oxidation catalyst. This converts to an emission factor of 0.00126 lb/MM BTU and a mass emission rate of 2.7 pounds per hour. This is more stringent that the current ARB BACT determination of 2 ppmvd @ 15% $O_{2,}$, averaged over 1 hour, as promulgated in their power plant siting guidance document that was adopted on July 22, 1999. This emission rate is also more stringent than the POC emission rate established for the recently permitted Delta Energy Center, which was approved by the EPA and ARB at its permitted rate of 2 ppmvd POC @ 15% O_2.

Sulfur Dioxide (SO_2)

- Combustion Gas Turbines

  District BACT Guideline 89.2.1 specifies BACT for SO_2 for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as the exclusive use of clean-burning natural gas. The proposed turbines will utilize natural gas exclusively, with an expected sulfur content of 0.20 grains per 100 scf, which will result in minimal SO_2 emissions. This corresponds to an SO_2 emission factor of 0.0006 lb/MM BTU. The natural gas sulfur content specification of 0.20 grains per 100 scf is deemed BACT for SO_2.

- Heat Recovery Steam Generators (HRSGs)

  As is the case of the Gas Turbines, BACT for SO_2 for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with an expected sulfur content of 0.02 grains per 100 scf. This corresponds to an SO_2 emission factor of 0.0006 lb/MM BTU.

Particulate Matter (PM_{10})

- Combustion Gas Turbines

  District BACT Guideline 89.2.1 specifies BACT for PM_{10} for gas turbines with a heat input rating $\geq$ 23 MM BTU per hour as the exclusive use of clean-burning natural gas. The proposed turbines will utilize natural gas exclusively, which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as sulfates. Because the sulfur content of the natural gas is not expected to exceed 0.20 grains per 100 scf, the sulfate particulate formation will be minimized.

- Heat Recovery Steam Generators (HRSGs)

  As is the case of the Gas Turbines, BACT for PM_{10} for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of 4 ppmv.

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NO_x emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. Because the MEC facility will emit more than 50 tons per year of NO_x, offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.1 and

302.2, NO_x offsets may be used to offset emission increases of POC and POC offsets may be used to offset emission increases of NO_x.
Pursuant to Regulation 2-2-303, emission offsets shall be provided (at a ratio of 1.0:1.0) for PM_{10} emission increases at new facilities that will be permitted to emit more than 100 tons of PM_{10} per year. Pursuant to Regulation 2-2-303.1, emission reduction credits of nitrogen oxides or sulfur dioxide may be used to offset PM_{10} emission increases.

Pursuant to District Regulation 2, Rule 2, Section 302, offsets are required only for permitted sources. Therefore, emission offsets will be required for the POC and NO_x emission increases associated with S-1 & S-3 Gas Turbines and S-2 & S-4 HRSGs only. Emission offsets will not be required for the POC and NO_x emissions from the exempt fire pump diesel engine and exempt emergency generator. Please see Appendix C for further detail.

It should be noted that in the case of POC and NO_x offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset.

Timing for Provision of Offsets

Pursuant to District Regulation 2-2-311, the applicant must "provide" the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct. Pursuant to District Regulation 2, Rule 3, "Power Plants," the Authority to Construct will be issued after the California Energy Commission issues the Certificate for the proposed power plant. Historically, the BAAQMD has not required the applicant to provide the actual banking certificates to the District prior to the issuance of the authority to construct. Rather, the District has accepted the applicant's demonstration of control of valid offsets through enforceable contracts or options to purchase as equivalent to the "provision" of offsets as required by Regulation 2-2-311. The actual banking certificates must be surrendered to the District prior to the issuance of the Permit to Operate.

Interpollutant Offset Ratios

Pursuant to District Regulations 2-2-302 and 2-2-302.2, emission reduction credits of precursor organic compounds may be used to offset increased emissions of nitrogen oxides at a ratio of 1.15 to 1.0.

Offset Requirements by Pollutant

The applicable offset ratios and the quantity of offsets required are summarized in Appendix C, Table C-1.

POC Offsets

Because the Metcalf Energy Center will emit greater than 15 tons per year, but less than 50 tons per year of Precursor Organic Compounds (POCs) from permitted sources, the POC emission increases must be offset at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-302. Furthermore, the offsets must be provided by the District Small Facility Banking Account. However, pursuant to Regulation 2-4-414, if the applicant possesses valid emission reduction credits, they must be utilized as a source of offsets prior to the granting of offsets from the Small Facility Banking Account. Pursuant to District Regulation, 2-2-302.1, the applicant has the option to provide NO_x ERCs to offset the proposed POC emission increases at the same ratio of 1.0 to 1.0.

NO_x Offsets

Because the Metcalf Energy Center will emit greater than 50 tons per year of Nitrogen Oxides (NO_x) from permitted sources, the applicant must provide emission reduction credits (ERCs) of NO_x at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302. Pursuant to District Regulation, 2-2-302.2, the applicant has the option to provide POC ERCs to offset the proposed NO_x emission increases at a ratio of 1.15 to 1.0.

PM_{10} Offsets

With projected PM_{10} emissions from permitted sources (including the cooling tower) of less than 100 tons per year, the Metcalf Energy Center does not trigger the PM_{10} offset requirement of District Regulation 2-2-303.

SO_2 Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed SO_2 emission increases associated with this project since the facility SO_2 emissions will not exceed 100 tons per year. Regulation 2-2-303 does allow for the voluntary offsetting of SO_2 emission increases of less than 100 tons per year. The applicant has not opted to provide such emission offsets.

Offset Package

Table 5 summarizes the current offset obligation of the Metcalf Energy Center and the quantity of valid emission reduction credits (ERCs) under the control of Calpine/Bechtel. The emission reduction credits presented in Table 5 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, “Emissions Banking”, and were subsequently issued as a banking certificate 625 by the BAAQMD under application 18791. Because the quantity of offsets issued under certificate 625 exceeded 40 tons per year, the application was subject to the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, the application was reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

As indicated, Calpine/Bechtel has secured an option to purchase sufficient valid emission reduction credits to offset the emission increases from the permitted sources proposed for the Metcalf Energy Center. As currently proposed, MEC will provide a combination of POC and NO_x emission reduction credits to offset the facility NO_x emission offset liability of 212.75 tons.

Table 5
Emission Reduction Credits Identified by Calpine/Bechtel as of August 21, 2000 (ton/yr)

	POC	NO_x	SO_2	PM_{10}
Valid Emission Reduction Credits				
Banking Certificate 625, Quebecor Inc., San Jose[a]	356	0	0	0
Banking Certificate 413, Folgers Coffee, San Jose[b]	0	1.31	0	0
Banking Certificate 426, Frito Lay, San Jose[c]	0	6.42	0	0
Banking Certificate 19, Glorietta Foods, San Jose[d]	0	32.24	0	0
Banking Certificate 507, Raisch Products, Mountain View[e]	0	6.50	0	0
Total ERC's Identified	356	46.47	0	0
Permitted Source Emission Limits	28	185	10.6	83.34
Offsets Required per BAAQMD Calculations	28[f]	212.75[g]	0	0
Outstanding Offset Balance	**+ 328**	**- 166.28[h]**	**0**	**0**

[a]Application 18791, issued 7/29/99; option agreement signed

[b]application 14192, issued 6/27/95

[c]application 14536, issued 7/11/95

[d]application 30051, issued 7/21/82

[e]application 16391, issued 7/2/96

[f]reflects applicable offset ratio of 1.0:1.0 pursuant to Regulation 2-2-302

[g]reflects applicable offset ratio of 1.15:1.0 pursuant to Regulation 2-2-302.2

[h]pursuant to District Regulation, 2-2-302.2, the applicant will provide POC ERCs to offset the outstanding NOx offset obligation

3. PSD Air Quality Impact Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts of the MEC project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the MEC facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards for NO_2, CO, and PM_{10} or an exceedance of any applicable PSD increment. **Table 6 summarizes** the applicable ambient air quality standards, the maximum background concentrations, and the contribution form the proposed MEC.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation.

Table 6
California and National Ambient Air Quality Standards (AAQS) and Ambient Air Quality Levels from the Proposed MEC (mg/m^3)

Pollutant	Averaging Time	Maximum Background	Maximum Project impact	Maximum Project impact plus maximum background	California Standards	National Standards
NO_2	1-hour	245	188	433	470	---
CO	8-hour	8167	549	8716	10,000	10,000
PM_{10}	24-hour	114.4	9.3	123.7	50[3]	150
	annual GM[1]	25	1.1	26.1	-	-
	annual AM[2]	29	1.1	30.1	30[3]	50

[1]GM-geometric mean [2]AM-arithmetic mean

[3]provided for informational purposes only; BAAQMD Regulations do not require a determination of non-interference with the attainment or maintenance of state PM_{10} AAQS

Because the maximum modeled project impacts for annual average NO_2 and 1-hour average CO did not exceed the significance level for air quality impacts per Regulation 2-2-233, further analysis to determine if the corresponding ambient air quality standards will be exceeded is not required per District regulations. Therefore, Table 6 does not list the AAQS and facility impacts for annual average NO_2 and 1-hour average CO. Please see Appendix E, Table E-3 for further detail. The entire PSD air quality impact analysis is contained in Appendix E.

B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the MEC project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the MEC are summarized on page 8, Table 2. In accordance with the requirements of the BAAQMD Toxic Risk Management Policy (TRMP) and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

Table 7 Health Risk Assessment Results

Source	Multi-pathway Carcinogenic Risk (risk in one million)	Non-carcinogenic Chronic Hazard Index	Non-carcinogenic Acute Hazard Index[a]
Gas Turbines, HRSGs, and Cooling Tower[b]	0.20	0.06	0.33
Fire Pump Diesel Engine	0.89[c]	0.0006	0.24

[a]included for informational purposes only; BAAQMD TRMP does not require an assessment of acute (short-term; i.e. < 24 hour) health impacts

[b]numbers represent combined risk from all sources

[c]because the location of maximum impact for the diesel engine does not coincide with the locations of maximum impact for the other sources, the total combined carcinogenic risk for the facility does not exceed 1 in one million

Because the increased risk due to the emission of particulate matter from the Fire Pump Diesel Engine is less than one in one million, the engine is exempt from District permit requirements pursuant to Regulation 2-1-114.2.3.1, since it will be operated for no more than 200 hours per calendar year, plus an additional 100 hours per calendar year for the purposes of maintenance and testing.

The health risk assessment performed by the applicant has been reviewed by the District Toxics Evaluation Section and found to be in accordance with guidelines adopted by Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the California Air Pollution Control Officers Association (CAPCOA). Pursuant to the BAAQMD Risk Management Policy, the increased carcinogenic risk attributed to this project is considered to be not significant since it is less than 1.0 in one million. The chronic hazard index attributed to the emission of non-carcinogenic air contaminants is considered to be not significant since it is less than 1.0. Therefore, the MEC facility is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy. Please see Appendix D for further discussion

Comments were received on the PDOC requesting that the emission rates for formaldehyde, acrolein, and acetaldehyde be revised based upon new emission factors recently published in AP-42, and a study conducted in August 1996 by Carnot Industries for the Electric Power Research Institute (EPRI). The EPRI study suggested that elevated formaldehyde emissions occur at partial turbine loads. In response to these comments, the applicant conducted a source test of a Westinghouse 501F turbine equipped with DLN combustors. The results of the source tests support the original emission estimates for formaldehyde, acrolein, and acetaldehyde utilized in the health risk assessment. Therefore, proposed MEC will not cause a significant health impact in accordance with the BAAQMD Toxic Risk Management Policy. Please see Appendix A for further discussion.

C. Other Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the PSD air quality impact analysis insures that the proposed facility will comply with this Regulation.

Regulation 2, Rule 1, Sections 301 and 302:
Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, the Metcalf Energy Center has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.

Because the proposed 10-cell cooling tower will not be used for the evaporative cooling of process water, it is exempt from District permit requirements (Regulation 2-1-301 and 2-1-302) pursuant to Regulation 2, Rule 1, Section 128.4. However, District Regulation 2-1-319.1, which was adopted on May 17, 2000 requires sources with emissions in excess of 5 tons per year of any regulated air pollutant to obtain permits to operate. As proposed, the cooling tower will emit 8 tons of particulate matter per year and will therefore require a permit to operate under this regulation.

The proposed 300 hp fire pump diesel engine is exempt from District permit requirements pursuant to Regulation 2-1-114.2.3.1, since it will be operated for no more than 200 hours per calendar year, plus an additional 100 hours per calendar year for the purposes of maintenance and testing. However, as a result of the designation of diesel exhaust particulate as toxic air contaminant by the Air Resources Board, a health risk screening must be performed to determine if the standby diesel engine will require a permit to operate pursuant to the BAAQMD Toxic Risk Management Policy and Regulation 2-1-319.2. Accordingly, the applicant submitted a health risk screening to determine the potential impact of the diesel particulate that will be emitted by the fire pump diesel engine. The screening showed that the resulting increased carcinogenic risk is less than one in one million. Therefore, the fire pump diesel engine remains exempt from District permit requirements pursuant to Regulation 2-1-114.2.3.1.

Because the proposed natural gas fired emergency generator has a rated heat input of 6.44 MM BTU/hour, it is exempt from District permit requirements pursuant to Regulation 2-1-114.2.3.1, since it will be operated for no more than 200 hours per calendar year, plus an additional 100 hours per calendar year for the purposes of maintenance and testing.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-405, this Final Determination of Compliance (FDOC) serves as the APCO's Final determination that the proposed power plant will meet the requirements of all applicable BAAQMD, state, and federal regulations. The FDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-404, this FDOC has fulfilled the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The FDOC does not serve as the PSD permit because the biological consultation process required to demonstrate compliance with the Endangered Species Act has not been completed. The Authority to Construct, when issued by the District, will be the PSD permit.

Regulation 2, Rule 6: Major Facility Review

Pursuant to Regulation 2, Rule 6, section 404.1, the owner/operator of the MEC shall submit an application to the BAAQMD for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Regulation 2-6-212.1, the MEC will become subject to Regulation 2, Rule 6 upon start-up.

Regulation 2, Rule 7: Acid Rain

The Metcalf Energy Center gas turbine units and heat recovery steam generators will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. Pursuant to 40 CFR Part 72.30(b)(2)(ii), MEC must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. Pursuant to 40 CFR Part 72.2, “commence operation” includes the start-up of the unit’s combustion chamber.

Regulation 6: Particulate Matter and Visible Emissions

Through the use of dry low-NO_x burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines and HRSG duct burners is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. As calculated in accordance with Regulation 6-310.3, the grain loading resulting from the simultaneous operation of each power train (CTG and HRSG Duct Burners) is 0.04 gr/dscf @ 6% O_2. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 5438 mg/l and corresponding maximum PM_{10} emission rate of 1.813 lb/hr, the proposed 10-cell cooling tower is expected to comply with the requirements of Regulation 6.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements but are subject to Regulation 6. It is expected that the conditions of certification imposed by the California Energy Commission will include requirements for construction activities that will require the use of water and/or chemical dust suppressants to minimize PM_{10} emissions and prevent visible particulate emissions.

Regulation 7: Odorous Substances

Regulation 7-302 prohibits the discharge of odorous substances which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia emissions from the two proposed CTG/HRSG power trains will each be limited by permit condition to 5 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Organic Compounds

This facility is exempt from Regulation 8, Rule 2, “Miscellaneous Operations” per 8-2-110 since natural gas will be fired exclusively at the MEC.

The use of solvents for cleaning and maintenance at the MEC is expected to comply with Regulation 8, Rule 4, “General Solvent and Surface Coating Operations” section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

Regulation 9: Inorganic Gaseous Pollutants

<u>Regulation 9, Rule 1, Sulfur Dioxide</u>

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level SO_2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over

24 hours. Section 302 (General Emission Limitation) prohibits SO_2 emissions in excess of 300 ppmv (dry). With maximum projected SO_2 emissions of < 1 ppmv, the gas turbines and HRSG duct burners are not expected to contribute to noncompliance with ground level SO_2 concentrations and should easily comply with section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

The proposed combustion gas turbines (each rated at 1,990.5 MM BTU/hr HHV) shall comply with the Regulation 9-3-303 NO_x limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.5 ppmvd @ 15% O_2. The HRSG duct burners have heat input ratings of less than 250 MM BTU/hr and therefore are not subject to this regulation. The proposed exempt emergency generator is not subject to this regulation since it has a heat input rating of 6.44 MM BTU/hr.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The proposed HRSGs are exempt from Regulation 9, Rule 7, per section 110.5 since they are used to recover sensible heat from the exhaust of the proposed combustion turbines.

Regulation 9, Rule 8, Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines

The proposed exempt 300 hp fire pump diesel engine is exempt from the requirements of Regulation 9, Rule 8 per Regulation 9-8-111 since they will be operated less than 200 hours in any consecutive twelve month period. The owner/operator must comply with Regulation 9-8-502, "Recordkeeping" to qualify for this low usage exemption.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because each of the proposed combustion gas turbines will be limited by permit condition to NO_x emissions of 2.5 ppmvd @ 15% O_2, they are expected to comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

V Permit Conditions

The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb/hr and lb/MM BTU of natural gas fired) will insure that daily and annual emission rate limitations are not exceeded.

To provide maximum operational flexibility, no limitations will be imposed on the type, or quantity of gas turbine start-ups or shutdowns. Instead, the facility must comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and NO_x limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up and shutdown. If the CO and NO_x CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable O_2 content and the differing response times of the O_2 and NO_x monitors, then start-up and shutdown mass emission rates will be based upon annual source test results. Compliance with POC, SO_2, and PM_{10} mass emission limits will be verified by annual source testing.

In addition to permit conditions that apply to steady-state operation of each CTG/HRSG power train, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems in place and the auxiliary boilers will operate without their SCR systems and oxidation catalysts in place. During this commissioning period, the gas turbines will be tested, control systems will be adjusted, and the HRSGs and auxiliary boiler steam tubes will be cleaned. Permit conditions 1 through 12 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedance of any short-term applicable ambient air quality standard.

Metcalf Energy Center
Permit Conditions

<u>Definitions:</u>

Clock Hour:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf.
Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.

Firing Hours: Period of time during which fuel is flowing to a unit, measured in fifteen minute increments.

MM BTU: million british thermal units

Gas Turbine Start-up Mode: The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d).

Gas Turbine Shutdown Mode: The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 20(b) through 20(d) until termination of fuel flow to the Gas Turbine.

Specified PAHs: The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds.

Benzo[a]anthracene
Benzo[b]fluoranthene
Benzo[k]fluoranthene
Benzo[a]pyrene
Dibenzo[a,h]anthracene
Indeno[1,2,3-cd]pyrene

Corrected Concentration: The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission point P-1 (combined exhaust of S-1 Gas Turbine and S-2 HRSG duct burners) and emission point P-2 (combined exhaust of S-3 Gas Turbine and S-4 HRSG duct burners) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis

Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the MEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems.

Commissioning Period: The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.

Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
MEC:	Metcalf Energy Center

Conditions for the Commissioning Period

1. The owner/operator of the Metcalf Energy Center (MEC) shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 and S-3 Gas Turbines and S-2 and S-4 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period. Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 47 shall apply after the commissioning period has ended.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the S-1 & S-3 Gas Turbine combustors and S-2 & S-4 Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-1 and A-2 SCR Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.

4. Coincident with the steady-state operation of A-1 & A-2 SCR Systems pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) shall comply with the NO_x and CO emission limitations specified in conditions 20(a) through 20(d).

5. The owner/operator of the MEC shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1 or S-3 Gas Turbines describing the procedures to be followed during the commissioning of the turbines, HRSGs, and steam turbine. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the required emission control systems, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) without abatement by their respective SCR Systems. Neither Gas Turbine (S-1 or S-3) shall be fired sooner than 28 days after the District receives the commissioning plan.

6. During the commissioning period, the owner/operator of the MEC shall demonstrate compliance with conditions 8 through 10 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   firing hours
   fuel flow rates
   stack gas nitrogen oxide emission concentrations,
   stack gas carbon monoxide emission concentrations
   stack gas oxygen concentrations.

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous monitors specified in condition 8 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4). After first firing of the turbines, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

9. The total number of firing hours of S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 25, except that total, cumulative NO_x mass emissions from S-1, S-2, S-3, and S-4 shall not exceed 185 tons during any consecutive twelve-month period which includes a portion of the Commissioning Period.

11. Combined pollutant mass emissions from the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1 & S-3).

NO_x (as NO_2)	5,266 pounds per calendar day	400.4 pounds per hour
CO	16,272 pounds per calendar day	1,192 pounds per hour
POC (as CH_4)	686 pounds per calendar day	
PM_{10}	756 pounds per calendar day	
SO_2	82.5 pounds per calendar day	

12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 21. The source test shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. Twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-1 & S-3) and the Heat Recovery Steam Generators (HRSGs; S-2 & S-4)

13. The Gas Turbines (S-1 and S-3) and HRSG Duct Burners (S-2 and S-4) shall be fired exclusively on natural gas. (BACT for SO_2 and PM_{10})

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 2,124 MM BTU per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 49,908 MM BTU per calendar day. (PSD for PM_{10})

16. The combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) shall not exceed 35,274,060 MM BTU per year. (Offsets)

17. The HRSG duct burners (S-2 and S-4) shall not be fired unless its associated Gas Turbine (S-1 and S-3, respectively) is in operation. (BACT for NO_x)

18. S-1 Gas Turbine and S-2 HRSG shall be abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-1 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

19. S-3 Gas Turbine and S-4 HRSG shall be abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

20. The Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for the S-1 Gas Turbine and the S-2 HRSG after abatement by A-1 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for the S-3 Gas Turbine and the S-4 HRSG after abatement by A-3 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. (PSD for NO_x)

    (b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

    (c) Carbon monoxide mass emissions at P-1 and P-2 each shall not exceed 0.0132 lb/MM BTU (HHV) of natural gas fired or 28.07 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

    (d) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 6.0 ppmv, on a dry basis, corrected to 15% O_2, when the heat input to the combustion turbine exceeds 1700 MM BTU/hr (HHV), averaged over any rolling 3-hour period. If compliance source test results and continuous emission monitoring data indicate that a lower CO emission concentration level can be achieved on a consistent basis (with a suitable complaince margin) over the entire range of turbine operating conditions, including duct firing and power steam augmentation operations, and over the entire range of ambient conditions, the District will reduce this limit to a level not lower than 4.0 ppmv, on a dry basis, corrected to 15% O_2. If this limit is reduced, the corresponding mass emission rate limit specified in condition 20(c) shall also be modified to reflect this reduction. (BACT for CO)

(e) Ammonia (NH_3) emission concentrations at P-1 and P-2 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-1 and A-2 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-1 and A-2 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 30. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.7 pounds per hour or 0.00126 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1 and P-2 each shall not exceed 1.28 pounds per hour or 0.0006 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 9 pounds per hour or 0.00452 lb PM_{10}/MM BTU of natural gas fired when HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 12 pounds per hour or 0.00565 lb PM_{10}/MM BTU of natural gas fired when HRSG duct burners are in operation. (BACT)

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 and S-3) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

	Start-Up (lb/start-up)	Start-Up (lb/hr)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	80	18
Carbon Monoxide (CO)	2,514	902	43.8
Precursor Organic Compounds (as CH_4)	48	16	5

22. The Gas Turbines (S-1 and S-3) shall not be in start-up mode simultaneously. (PSD)

23. The heat recovery steam generators (S-2 & S-4) and associated ducting shall be designed and constructed such that an oxidation catalyst can be readily installed and properly operated if

deemed necessary by the APCO to insure compliance with the CO emission rate limitations of conditions 20(c) and 20(d). (BACT)

24. Total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, and S-4), including emissions generated during Gas Turbine start-ups and shutdowns shall not exceed the following limits during any calendar day:

(a)	1,362.6 pounds of NO_x (as NO_2) per day	(CEQA)
(b)	7,891.1 pounds of CO per day	(PSD)
(c)	230.2 pounds of POC (as CH_4) per day	(CEQA)
(d)	510 pounds of PM_{10} per day	(PSD)
(e)	57.9 pounds of SO_2 per day	(BACT)

25. Cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, and S-4), including emissions generated during gas turbine start-ups and shutdowns shall not exceed the following limits during any consecutive twelve-month period:

(a)	123.4 tons of NO_x (as NO_2) per year	(Offsets)
(b)	588 tons of CO per year	(Cumulative Increase, PSD)
(c)	28 tons of POC (as CH_4) per year	(Offsets)
(d)	83.34 tons of PM_{10} per year	(Offsets)
(e)	10.6 tons of SO_2 per year	(Cumulative Increase)

26. The maximum projected annual toxic air contaminant emissions (per condition 29) from the Gas Turbines and HRSGs combined (S-1, S-2, S-3, and S-4) shall not exceed the following limits:

formaldehyde	3,796 pounds per year
benzene	480 pounds of per year
Specified polycyclic aromatic hydrocarbons (PAHs)	22.8 pounds of per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

27. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 21, 22, 24(a), 24(b), 25(a), and 25(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:
    (a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-2 combined and S-3 & S-4 combined.
    (b) Oxygen (O_2) Concentrations, Nitrogen Oxides (NO_x) Concentrations, and Carbon Monoxide (CO) Concentrations at each of the following exhaust points: P-1 and P-2.
    (c) Ammonia injection rate at A-1 and A-2 SCR Systems
    (d) Steam injection rate at S-1 & S-3 Gas Turbine Combustors

    The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

    The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

    (e) Heat Input Rate for each of the following sources: S-1 & S-2 combined and S-3 & S-4 combined.
    (f) Corrected NO_x concentrations, NO_x mass emissions (as NO_2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-1 and P-2.

    For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 27(e) and 27(f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

    (g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.
    (h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3, and S-4) combined.
    (i) the average NO_x mass emissions (as NO_2), CO mass emissions, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.
    (j) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-1, S-2, S-3, and S-4) combined.

(k) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentrations, NO_x mass emissions (as NO_2), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.

(l) on a daily basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-1, S-2, S-3, and S-4) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

28. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 21, 24(c) through 24(e), and 25(c) through 25(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO_2) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 27, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM_{10}, and SO_2 emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-1, S-2, S-3, and S-4) combined.

(b) on a daily basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all four sources (S-1, S-2, S-3, and S-4) combined.

(Offsets, PSD, Cumulative Increase)

29. To demonstrate compliance with Condition 26, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 35,274,060 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of Heat Input) determined by any source test of the S-1 & S-3 Gas Turbines and/or S-2 & S-4 Heat Recovery Steam Generators. (TRMP)

30. Within 60 days of start-up of the MEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-1 or A-2 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1 or P-2. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and 100% load) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

31. Within 60 days of start-up of the MEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 29. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. (BACT, offsets)

32. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

33. Within 60 days of start-up of the MEC and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 26. The gas turbine shall also be tested at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 29 for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	≤	26.8 pounds/year
Formaldehyde	≤	132 pounds/year
Specified PAH's	≤	0.18 pounds/year

(TRMP)

34. The owner/operator of the MEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

35. The owner/operator of the MEC shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

36. The owner/operator of the MEC shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

37. The stack height of emission points P-1 and P-2 shall each be at least 145 feet above grade level at the stack base. (PSD, TRMP)

38. The Owner/Operator of MEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval. (Regulation 1-501)

39. Within 180 days of the issuance of the Authority to Construct for the MEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 27, 30, 31, 33, and 47. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

40. Prior to the issuance of the BAAQMD Authority to Construct for the Metcalf Energy Center, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 212.75 tons/year of Nitrogen Oxides and 28 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2) are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

41. Prior to the start of construction of the Metcalf Energy Center, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 212.75 tons/year of Nitrogen Oxides and 28 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2. (Offsets, CEC)

42. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the MEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of the issuance of the PSD permit for the MEC. (Regulation 2-6-404.1)

43. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Metcalf Energy Center shall submit an application for a Title IV operating permit to the BAAQMD. Operation of any of the gas turbines (S-1 & S-3) or HRSGs (S-2 & S-4) without a Title IV operating permit may not occur sooner than 24 months after the application is received by the BAAQMD. (Regulation 2, Rule 7)

44. The Metcalf Energy Center shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

45. The owner/operator shall take monthly samples of the natural gas combusted at the MEC. The samples shall be analyzed for sulfur content using District-approved laboratory methods. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. (cumulative increase)

46. The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 5,438 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

47. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the Metcalf Energy Center, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. Within 60 days of the initial operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 46. The CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in condition 46. (PSD)

VI Recommendation

The APCO has concluded that the proposed Metcalf Energy Center power plant, which is composed of the permitted sources listed below, complies with all applicable District rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

S-1 Combustion Gas Turbine #1, Westinghouse 501FD2; 1,990.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-1 Selective Catalytic Reduction System

S-2 Heat Recovery Steam Generator #1, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-1 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #2, Westinghouse 501FD2; 1,990.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-2 Selective Catalytic Reduction System

S-4 Heat Recovery Steam Generator #2, equipped with dry low-NO_x Duct Burners, 200 MM BTU per hour, abated by A-2 Selective Catalytic Reduction System

Pursuant to District Regulation 2-3-404, this document has fulfilled the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. A notice inviting written public comment was published in the San Jose Mercury News on April 26, 2000. The public comment period ended on May 31, 2000.

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